GLEN CANYON DAM INTERIM OPERATIONS

Estimated Net Expense

December 1993 through March 1994

WESTERN
AREA POWER ADMINISTRATION

May 1994

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TABLE OF CONTENTS

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I. EXECUTIVE SUMMARY

Power Scheduling and Real-Time Operations

- The Los Angeles earthquake of January 17 severed transmission to several utilities within the northwest and southwest market area, resulting in selling surplus energy from the Los Angeles Department of Water and Power at $18.50/MWh. Western, by purchasing this abundant energy, was able to reduce 50,000 acre-feet from projected releases to be used for the upcoming summer months.

- In early February cold weather and unit outages in the Four Corners Area created an energy shortage in which RMGC could only provide 50 MWh out of an agreed 90 MWh. Surplus Navajo generation provided for the lost portion from RMGC. Prices for onpeak non-firm energy escalated to $30/MWh for the week of February 7, in contrast to the average onpeak purchase price of $26.75/MWh for all of February.

Analysis of Ramping Events

- There were 95 deviations: "Control Area Regulation" accounted for most of the anomalies.

Expenses

- Net expense of interim releases:

December 1993	$551,942
Janaury 1994	$373,668
February 1994	$465,858
March 1994	$343,725

Power Scheduling Concerns (Future)

- Expected resumption of the fish release program by BPA from May through July should deliver a surplus of low cost energy to the non-firm energy market. Western has contracted for an allotment of this economical energy to ameliorate the reductions in power generation from the special releases.

II. INTRODUCTION

On August 1, 1991, former Interior Secretary Manual Lujan implemented interim flows at Glen Canyon Dam. These interim flows were a considerable departure from previous operation of the dam and have had a

significant impact on the daily operation of Western Area Power Administration's (Western) Upper Colorado Control Area.

The impacts of this change in dam operations have required Western to implement new scheduling procedures for its customers, develop interim release guidelines for real-time operations, purchase higher-priced energy during onpeak periods, and increase the firm-power rates to its customers to cover the additional costs.

The following sections are a review of Power Operations for the reporting period.

III. SCHEDULING

A. Interim release restrictions have limited Western's ability to accommodate hourly changes in the preschedules. These restrictions have required Western to request customer prescheduling 3 days in advance in order to match firm loads to available project resources and substitute purchases for any hourly deficits. Hourly changes to preschedules have been restricted by the lack of system flexibility. The burden to adjust to changes in real-time load has shifted from the contractors' use of their SLCA/IP resources to the contractors' alternate resources. A majority of these other resources are thermal and have higher costs associated with their use.

B. Power Scheduling and Real-Time Operations

1. Power Scheduling and Purchases for December 1993

December water releases from Glen Canyon totaled 800,000 acre feet (AF). The weekday generation pattern was pre-scheduled at approximately 10,000 cfs (390 MW) during offpeak hours ramping up to a maximum of 17,000 cfs (663 MW) during onpeak hours for a majority of the month, staying within the daily maximum fluctuation restriction of 8,000 cfs (273 MW) per day. Weekend releases were adjusted downward to follow reduced weekend loads.

December's weather was mild, allowing for consistent allocation scheduling by SLCA/IP contractors'. Water allocated for December placed the daily fluctuation restriction at 8,000 cfs (800,000 AF). High test flows at Flaming Gorge and ramping restrictions (one daily peak limited to 30 MW, up ramp and down ramp) limited the exposure of the trout population to high fluctuations. Western's long-term purchase contracts were curtailed for the first half of the month because of high releases. These unplanned reductions in purchases resulted in decreased revenue for utilities that have long-term purchase agreements with Western.

2. Power Scheduling and Purchases for January 1994

January water releases from Glen Canyon totaled 806,000 AF. At the beginning of the month, generation fluctuated between 10,500 cfs (408 MW) and 18,500 cfs (719 MW). At the end of the month, generation was pre-scheduled at 9,500 cfs (368 MW), ramping up to

16,500 cfs (640 MW). The daily maximum fluctuation restriction of 8,000 cfs (273 MW) was followed for the entire month.

The first week of January, the Bureau scaled down its snowpack projections, reducing Glen Canyon releases for WY 1994 to 8,230,000 AF, resulting in cut backs in the generation from Glen Canyon and the Aspinall units to save water for summer operations.

The January 17th Los Angeles earthquake tested the efficacy of the Salt Lake City Area and the Southwestern interconnected systems. Large transmission segments and load centers in the Los Angeles region were displaced, effectively severing several interconnect ties to utilities in the Southwest and the Northwest. The Los Angeles Department of Water and Power (LADWP), had surplus energy availability because of its inability to reach its load areas. Western purchased 100 MW/hour of this discounted energy from LADWP for $18.50/MWh. For the week of January 14, before the earthquake, onpeak non-firm energy was purchased by Western at $27.00/MWh, resulting in an $8.50/MWh reduction in energy prices after the Los Angeles earthquake. By the end of the month, onpeak nonfirm energy prices rebounded to $24.00/MWh (Secretary's Report, January 28, 1994). Western reduced releases from Glen Canyon to achieve a target of 800,000 AF for the month, a reduction of 50,000 AF from projected releases, allowing Western to save water for the summer months.

3. Power Scheduling and Purchases for February 1994

February water releases from Glen Canyon totaled 689,000 AF. The weekday generation pattern was pre-scheduled at approximately 10,000 cfs (390 MW) during offpeak hours ramping up to a maximum of 16,000 cfs (618 MW) during onpeak hours for a majority of the month, staying within the daily maximum fluctuation restriction of 6,000 cfs (232 MW) per day. Weekend releases were adjusted downward to follow reduced weekend loads.

In early February the availability of economy energy was tight due to cold weather and unit outages in the Four Corners Area of Utah, Arizona, Colorado, and New Mexico. For several days, Rocky Mountain Generation Cooperative (RMGC) could only provide 50 MWh of the 90 MWh, that was agreed upon for February. Surplus Navajo generation from Lower Colorado was used to replace a portion of the RMGC energy (Secretary's Report, February 11, 1994). Prices for onpeak non-firm energy escalated to $30/MWh for the week of February 7, in contrast to the average onpeak purchase price of $26.75/MWh for the entire month of February.

On February 21 and 22, the Bureau conducted a unit acceptance test for Morrow Point, resulting in decreased generation from Morrow Point and Blue Mesa. The Glen Canyon monthly release target was not met by approximately 9,000 AF, due to the test. Purchase power requirements, during this test, were met by long-term agreements with RMGC and Navajo (Secretary's Report., February 25, 1994).

4. Power Scheduling and Purchases for March 1994

March water releases from Glen Canyon totaled 607,000 AF. The weekday generation pattern was pre-scheduled at approximately 6,500 cfs (251 MW) during offpeak hours ramping up to a maximum of 12,500 cfs (472 MW) during onpeak hours, staying within the daily maximum fluctuation restriction of 6,000 cfs (232 MW) per day. Weekend releases were adjusted downward to follow reduced weekend loads.

March was a warm month, reflecting a stable economy energy market, with onpeak non-firm energy prices hovering around $22-23/MWh. There were no events requiring a scheduling adjustment to Glen Canyon generation. The diversion tunnel was opened in March which increased generation capability from the Aspinall units.

C. Future Scheduling Concerns for May-September 1994

Coordination of special releases from Flaming Gorge and the Aspinall units are expected to be difficult to schedule for the Montrose Power Control staff. Due to low snowpack conditions, the spring runoff peak is expected to arrive 3 weeks earlier than projected. This has required Montrose to make adjustments to their non-firm energy purchase plans.

It is anticipated that Bonneville Power Administration (BPA) will begin its fish release program, from May through July, delivering a surplus of low cost energy to the market. Western has contracted for an allotment of this low cost energy to help alleviate the reductions expected in power generation from the special releases.

A future concern of Montrose is the combined effect of the scheduled spike release from Glen Canyon and the ongoing studies at Flaming Gorge and the Aspinall units that will take place in April of WY 1995.

IV. ANALYSIS OF RAMPING EVENTS

A study was made to analyze hourly release rates which appeared to deviate from interim flow criteria. Operational records and logs kept during the study period, December 1, 1993, through March 31, 1994 were reviewed.

The operational records and logs are contained within the packet Glen Canyon Dam Interim Flows—Glen Canyon Power Plant Operations, for December 1993 through March 1994 and provide specific explanations for each ramping event.

Each page within the packet contains: (1) a strip chart of real-time Glen Canyon Dam operations during the ramping event, (2) a graph of the USGS Lee's Ferry Gauge showing river elevation during the ramping event, (3) a graph of hourly integrated Glen Canyon Dam generation during the ramping event, and (4) a brief written explanation of the ramping event.

For the study period, 95 instances of deviations were found. Most of the conditions were caused by more than one factor: (e.g., control area regulation and imports/exports different than preschedule), therefore, multiple variations can be explained by one anomaly.

The following table summarizes the causes and frequency of the 95 deviations:

Primary Cause(s) of Deviation	Number Of Instances	Percent Of Events
Control Area Regulation	37/95	39
Control Area Disturbance	10/95	11
CRSP Resource Availability	9/95	9
Aspinall Operations	4/95	4
Morrow Point Operations	1/95	1
Blue Mesa Operations	2/95	2
Imports/Exports Different than Preschedule	19/95	20
Other	13/95	14

V. EXPENSES

A. Net Expense

The estimated net expense of interim releases for December 1993 through March 1994 are summarized below:

	Net Expense
December 1993	$551,942
January 1994	$373,668
February 1994	$465,858
March 1994	$343,725

Attached are Tables 1 through 4 detailing the net expense analysis by component for December 1993, January 1994, February 1994, and March 1994.

B. Purchases

A comparison of Base Case purchases to Actual purchases are summarized below:

Energy Purchase Comparison			
Months	Simulated Base Case Purchases	Actual Purchases	Differences
December 1993	92,409 MWh	26,865 MWh	65,544 MWh
Janaury 1994	93,988 MWh	47,492 MWh	46,496 MWh
February 1994	98,223 MWh	84,278 MWh	13,945 MWh
March 1994	128,707 MWh	125,803 MWh	2,904 MWh

For December 1993 through March 1994, actual purchases were less than simulated Base Case purchases. This is due to a shift in deficits from onpeak to offpeak hours in the Base Case, resulting in higher purchases during offpeak hours.

C. Economy Energy Sales (Surplus)

For all months, actual nonfirm energy sales were less than projected for Base Case conditions. Revenues foregone are estimated below:

ENERGY SALES AND REVENUES FOREGONE			
Months	**Base Case**	**Actual**	**Revenues Foregone**
December 1993	$1,789,425	$314,708	$1,474,717
January 1994	1,014,665	104,739	909,926
February 1994	237,303	204	237,099
March 1994	56,658	2,818	53,840

D. Average Purchase Prices—Base Case and Actual

The average monthly purchase price estimates are derived from the actual nonfirm energy purchase prices. With the help of the Power Control staff (Montrose), some of the higher purchase prices for all months that are associated directly with interim release constraints, were excluded. An adjusted weighted average of remaining purchase amounts and prices are rendered to calculate the base case offpeak and onpeak purchase prices.

Average Base Case monthly purchase prices are estimated as follows:

ENERGY PURCHASE PRICES				
	Base Case		Actual	
Months	Offpeak	Onpeak	Offpeak	Onpeak
December 1993	$16.34/MWh	$24.07/MWh	$16.44/MWh	$24.08/MWh
January 1994	15.97/MWh	21.80/MWh	15.97/MWh	21.86/MWh
February 1994	16.16/MWh	24.24/MWh	16.26/MWh	24.28/MWh
March 1994	16.43/MWh	23.48/MWh	16.52/MWh	23.49/MWh

E. Economy Energy Sales Prices—Base Case and Actual

The sales price for the Base Case is determined with the help of the Montrose Power Control Staff (Montrose). The estimate of economy energy sales prices involve three steps:

1. Identification of the range of market prices through review of Montrose District Office Power Control staff's summaries of then-current weekly market prices, as reflected in Western's Weekly Reports to the Secretary.

2. Review of the actual monthly economy energy sales summary and, with the help of the Power Control staff, identification of those forced sales directly associated with interim release constraints.

3. Assumption of expected sales price based on then-current market conditions for that portion of sales identified in step 2.

In most instances, Western would have had the flexibility of making all or most of the nonfirm energy sales during periods when the value is greatest. For all months, the economy energy sales prices under the Base Case is the same as the actual sales price, reflecting no forced sales within this period.

Presented below is a comparison of average monthly economy energy sales for Base Case prices to Actual prices. Since there are no differences between the Base Case prices and Actual prices, there were no forced sales during this reporting period.

ECONOMY ENERGY SALES PRICES BASE CASE & ACTUAL			
Months	**Base Case Prices**	**Actual Prices**	**Differences Between Base Case Prices and Actual Prices**
December 1993	$22.50/MWh	$22.50/MWh	$0.00/MWh
January 1994	19.57/MWh	19.57/MWh	0.00/MWh
February 1994	17.00/MWh	17.00/MWh	0.00/MWh
March 1994	18.54/MWh	18.54/MWh	0.00/MWh

Table 1
Glen Canyon Dam Interim Release
for December 1993
Net Expense Analysis

Base Case (Without Interim Release)		Actual (With Interim Release)	
Firm Load & Losses:	525,118 MWh	Firm Load & Losses:	525,118 MWh
GC Generation:	378,966 MWh	GC Generation:	378,966 MWh
Other CRSP/IP Generation:	133,274 MWh	Other CRSP/IP Generation:	133,274 MWh
Total Generation:	512,240 MWh	Total Generation:	512,240 MWh
Purchases:	92,409 MWh	Purchases:	26,865 MWh
Off Peak:	92,409 MWh	Off Peak:	7,817 MWh
On Peak:	0 MWh	On Peak:	19,048 MWh
Surplus:	79,530 MWh	Surplus:	13,987 MWh
Off Peak:	10,091 MWh	Off Peak:	7,129 MWh
On Peak:	69,439 MWh	On Peak:	6,858 MWh
Purchase Prices:		Purchase Prices:	
Off Peak:	$16.34/MWh	Off Peak:	$16.44/MWh
On Peak:	$24.07/MWh	On Peak:	$24.08/MWh
Sales Price:	$22.50/MWh	Sales Price:	$22.50/MWh
Purchase Expense:	$1,509,963	Purchase Expense:	$587,187
Off Peak:	$1,509,963	Off Peak:	$128,511
On Peak:	$0	On Peak:	$458,676
Surplus Sales:	$1,789,425	Surplus Sales:	$314,708
Base Case Expense:	($279,462)	Change Case Expense:	$272,480

Total Net Expense for December 1993 ..... $551,942

Table 2
Glen Canyon Dam Interim Release
for January 1994
Net Expense Analysis

Base Case (Without Interim Release)		Actual (With Interim Release)	
Firm Load & Losses:	521,955 MWh	Firm Load & Losses:	521,955 MWh
GC Generation:	376,928 MWh	GC Generation:	376,928 MWh
Other CRSP/IP Generation:	102,887 MWh	Other CRSP/IP Generation:	102,887 MWh
Total Generation:	479,815 MWh	Total Generation:	479,815 MWh
Purchases:	93,988 MWh	Purchases:	47,492 MWh
Off Peak:	93,935 MWh	Off Peak:	12,417 MWh
On Peak:	53 MWh	On Peak:	35,075 MWh
Surplus:	51,848 MWh	Surplus:	5,352 MWh
Off Peak:	7,143 MWh	Off Peak:	2,095 MWh
On Peak:	44,705 MWh	On Peak:	3,257 MWh
Purchase Prices:		Purchase Prices:	
Off Peak:	$15.97/MWh	Off Peak:	$15.97/MWh
On Peak:	$21.80/MWh	On Peak:	$21.86/MWh
Sales Price:	$19.57/MWh	Sales Price:	$19.57/MWh
Purchase Expense:	$1,501,297	Purchase Expense:	$965,039
Off Peak:	$1,500,142	Off Peak:	$198,299
On Peak:	$1,155	On Peak:	$766,740
Surplus Sales:	$1,014,665	Surplus Sales:	$104,739
Base Case Expense:	$486,632	Change Case Expense:	$860,300

Total Net Expense for January 1994 ..... $373,668

Table 3
Glen Canyon Dam Interim Release
for February 1994
Net Expense Analysis

Base Case (Without Interim Releases)		Actual (With Interim Release)	
Firm Load & Losses:	469,607 MWh	Firm Load & Losses:	469,607 MWh
GC Generation:	323,441 MWh	GC Generation:	323,441 MWh
Other CRSP/IP Generation:	61,900 MWh	Other CRSP/IP Generation:	61,900 MWh
Total Generation:	385,341 MWh	Total Generation:	385,341 MWh
Purchases:	98,223 MWh	Purchases:	84,278 MWh
Off Peak:	93,333 MWh	Off Peak:	23,780 MWh
On Peak:	4,890 MWh	On Peak:	60,498 MWh
Surplus:	13,959 MWh	Surplus:	12 MWh
Off Peak:	1,298 MWh	Off Peak:	2 MWh
On Peak:	12,661 MWh	On Peak:	10 MWh
Purchase Prices:		Purchase Prices:	
Off Peak:	$16.16/MWh	Off Peak:	$16.26/MWh
On Peak:	$24.24/MWh	On Peak:	$24.28/MWh
Sales Price:	$17.00/MWh	Sales Price:	$17.00/MWh
Purchase Expense:	$1,626,795	Purchase Expense:	$1,855,554
Off Peak:	$1,508,261	Off Peak:	$386,663
On Peak:	$118,534	On Peak:	$1,468,891
Surplus Sales:	$237,303	Surplus Sales:	$204
Base Case Expense:	$1,389,492	Change Case Expense:	$1,855,350

Total Net Expense for February 1994 ..... $465,858

Table 4
Glen Canyon Dam Interim Release
for March 1994
Net Expense Analysis

Base Case (Without Interim Releases)		Actual (With Interim Release)	
Firm Load & Losses:	474,687 MWh	Firm Load & Losses:	474,687 MWh
GC Generation:	285,864 MWh	GC Generation:	285,864 MWh
Other CRSP/IP Generation:	63,172 MWh	Other CRSP/IP Generation:	63,172 MWh
Total Generation:	349,036 MWh	Total Generation:	349,036 MWh
Purchases:	128,707 MWh	Purchases:	125,803 MWh
Off Peak:	99,812 MWh	Off Peak:	49,765 MWh
On Peak:	28,895 MWh	On Peak:	76,038 MWh
Surplus:	3,056 MWh	Surplus:	152 MWh
Off Peak:	194 MWh	Off Peak:	0 MWh
On Peak:	2,862 MWh	On Peak:	152 MWh
Purchase Prices:		Purchase Prices:	
Off Peak:	$16.43/MWh	Off Peak:	$16.52/MWh
On Peak:	$23.48/MWh	On Peak:	$23.49/MWh
Sales Price:	$18.54/MWh	Sales Price:	$18.54/MWh
Purchase Expense:	$2,318,366	Purchase Expense:	$2,608,250
Off Peak:	$1,639,911	Off Peak:	$822,118
On Peak:	$678,455	On Peak:	$1,786,133
Surplus Sales:	$56,658	Surplus Sales:	$2,818
Base Case Expense:	$2,261,708	Change Case Expense:	$2,605,432

Total Net Expense for March 1994 ..... $343,725

TABLE 5
GLEN CANYON DAM INTERIM RELEASE
Summary of Estimated Actual Net Expense
Associated With Interim Release

WY 1993 Cumulative Net Expense $10,523,219

Month/Yr	Estimated Actual Net Expense	Cumulative Estimated Actual Net Expense
October 1993	$387,899	$10,911,118
November 1993	$464,447	$11,375,565
December 1993	$551,942	$11,927,507
January 1994	$373,668	$12,301,175
February 1994	$465,858	$12,767,033
March 1994	$343,725	$13,110,758

WY 1994 Net Expense $2,587,539
Cumulative Net Expense $13,110,758